Analysis of time lapse seismic signal analysis for an EOR and CCS site, Cranfield, MS

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Analysis of time lapse seismic signal for an EOR and CCS site, Cranfield, MS

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Summary

The Cranfield, MS EOR field site has been under CO_2 flood by Denbury Onshore, LLC since 2008. More than 3 million tons of CO_2 has been injected.

Time-lapse 3D surface seismic data displayed a readily observable signal related to CO_2 injection into the lower Tuscaloosa Formation. The intensity and the spatial distribution of time-lapse (TL) signal required further analysis. For that purpose, we carried out fluid substitution analysis, followed by volumes cross-equalization, well ties, and acoustic impedance inversions.

A Gassmann workflow was used to predict the response to injected CO_2 at two well locations. The 31F-2 observation well, located in a detailed area of study (DAS), was used to compare the results of time-lapse sonic data with fluid substitution results. The objective was to predict a post-injection saturation curve. A second well, well 28-1, was used to help predict an acoustic impedance change in the reservoir to use for subsequent inversion.

Finally, a model based inversion was performed to quantify the impedance change between two cross-equalized time-lapse data sets. The acoustic impedance (AI) difference obtained through the inversion process is higher than that predicted for in the 28-1 injection well. The time-lapse AI signal is however in agreement with the large velocity change computed from the time delay along the marker horizon below the reservoir.

Introduction

The Cranfield field, located in southwest Mississippi (Figure 1), was initially produced from 1943-1966 by Chevron. A large gas cap was located at the top domal structure in the Tuscaloosa Formation. The gas was originally recycled into the cap, for pressure maintenance, before being produced at the end of production in the 1960's.

By 2008 Denbury Onshore, LLC completed leasing and unitization of the Cranfield field. Continuous CO_2 injection into the Tuscaloosa Formation for enhanced oil recovery (EOR) commenced in mid-2008. This formation comprises of lithic-fragment-rich sandstone, muddy sandstones, and cross-bedded chert-conglomerates. The porosity lies between 14 and 26%, averaging about 20% with a permeability of <500mD in the reservoir. In addition to commercial injection, CO_2 was also injected into the brine leg of the field between 10414-10495ft (3174-3199m) in a detailed area of study on the east side of the field. As of this writing, more than three million tons of CO_2 remain in the subsurface.

A baseline 3-D seismic survey was collected in 2007 over the entire field and into the brine leg and shows a strong response from the residual gas. A repeat 3-D survey was collected in 2010 over the north-eastern portion of the field. One injection well and two observation wells are located in the eastern edge of the repeat volume in the detailed area of study, or "DAS." The 31F-2 observation well, located in the brine leg, has a baseline and repeat sonic well log which was used for the fluid substitution and inversion analysis. The 28-1 well, located in the oil rim in the northern section of the repeat volume, was used for fluid substitution and a model-based inversion assuming 30% residual oil saturation.

The purpose of this study is to improve our understanding of the observed time-lapse (4D) seismic signal which we expect to be affected by residual oil and gas throughout the field. In order to do this, the two data sets were cross-equalized and an acoustic inversion was conducted. The inversion results were then compared with fluid substitution results using a Gassmann fluid substitution workflow.

Integration of interpreted seismic response with forward modeling is used to understand the observed time lapse signal in relation to fluid properties and distribution. The ability to model out of zone migration of CO_2 can improve conformance for the containment of CO_2, an important aspect of any CO_2 sequestration project. Characterizing an effect in the subsurface is controlled by repeatability of the data, rock physics, fluid properties, and the heterogeneity of the reservoir. Site-specific studies to detect injected CO_2 have been conducted at CO_2 sequestration sites at Ketzin (Kazemeini et al., 2010), and Otway (Pevzner et al., 2010b) as well as the Aztbach-Schwanenstadt gas field (Rossi et al., 2008).

Time-lapse seismic signal prediction

A rock physics model based on a Gassmann-Wood workflow (Mavko et al., 1998) was used for the 31F-2 baseline and repeat sonic well log data. Kg (bulk grain) was computed from the mineral composition logs from 31-F1 well located 69m from the observation well. Uniform saturation was assumed. The input logs were used to calculate new set of elastic properties for the cases when we have: 3, 6, 9, 12, 15, and 20% CO_2 saturation.

Computed P-wave velocities for these saturation levels were compared to the measured time lapse sonic log values. From there we backed out the saturation profile, using the points where measured and computed P-wave velocity curves after CO_2 injection agreed (Figure 2).

The 28-1 injection well was also used for fluid substitution, but with a different purpose. This well is located in the oil rim of the volume and thus has residual oil saturation. Site-specific mineral composition was available at this location using well logs similar to those used for fluid substitution in the 31F-2 well. A Gassmann-Wood workflow was also used here, assuming 30 and 40% residual oil saturation. As expected, the two results were very similar; therefore, 30% saturation was used for the rest of the analysis. The p-wave velocities were used to compute acoustic impedance (AI) differences for 3, 6, 9, 12, 15, and 20% CO_2 saturation (Figure 3a and 3b, respectively). The computed time-lapse signal at different saturations was compared with the AI difference observed in the model-based inversion.

Cross-correlation of data

The two seismic volumes (2007 and 2010, respectively) were first cross-equalized (Figure 4) to enable subsequent differentiation. The difference cube displayed a coherent time lapse response at the reservoir level (2280ms approximately, Figure 5a).

A time-shift was calculated between the two seismic volumes below the reservoir at 2800ms. The result shows a time difference varying from +3ms to -3 ms (Figure 6b). The absolute change ranges from 1.2 to 3ms. For the given reservoir thickness of 26m this would translate to a compressional velocity change of approximately 250-500 m/s across the reservoir. Hence, the expected upper limit of the impedance change due to CO_2 injection is $-1.5 \cdot 10^6$ Kg/m^2s, while the minimum expected change in AI for time delay of 1.2 ms would be $-0.71 \cdot 10^6$ Kg/m^2s.

Model-Based Inversion

A 3D impedance model was built based on a single well, 28-1, and picked 3D horizons. Hampson-Russell software package was used for well tie and impedance volume construction. The lack of density log in the only well available made the process of inversion practically unconstrained. We then calculated density from the effective porosity log available. This result differs by up to 10% when calculating a density log using Gardner's equation (Gardner, 1974).

Pre-injection p-wave logs from the 28-1 well, displayed correlation coefficient of around 0.75 for a window around the reservoir. This well log and 3D seismic horizons were used to build an initial acoustic impedance model for the model-based inversion. In any case, more logs would have been required to improve the inversion results. It is therefore no surprise that a relatively low correlation value was obtained.

Both volumes, baseline and after CO_2 injection, were inverted with a zero-phase statistical wavelet which was extracted from baseline data. The AI difference through a window centered on the horizon is shown in Figure 7c. A similarity of this result with the equivalent difference computed from amplitude volumes is apparent.

Conclusions

The calculated saturation curve at the well suggests an average CO_2 saturation curve of about 9% in the reservoir. This can be used to estimate CO_2 saturation from the time-lapse 3D inversion response over the entire reservoir.

The maximum change in the predicted AI computed at well 28-1 is $-0.62 \cdot 10^6$ Kg/m^2s at 20% CO_2 saturation. The change in AI calculated from the time delay inferred from the horizon below the reservoir is about 2.5 times larger. The inversion, despite practically being unconstrained, suggests an average change near the 28-1 well of about $-0.91 \cdot 10^6$ Kg/m^2s which is only slightly higher than the time lapse change predicted for well 28-1. The maximum difference, however, found in the inverted cube was $-2.4 \cdot 10^6$ Kg/m^2s, which is similar to the one found from the time delay analysis. Both results based on seismic data analysis (AI and time delay) suggest more elevated CO2 time lapse response than we find at the well 28-1. This is not surprising as the information from seismic data comes over Fresnel radius rather than a single point.

Further refinement of the fluid substitution process is needed as well as more logs to verify the prediction and inversion process throughout the volume.

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Figure 1. Location of Cranfield, Mississippi. Image by Google Earth.

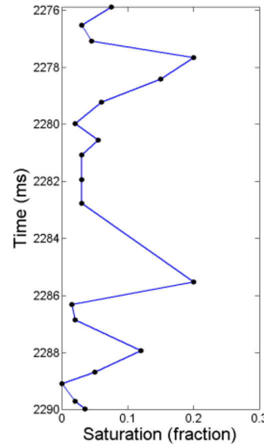

Figure 2. Plot of saturation curve extracted from the intersections of the computed and measured P-wave velocity profile within the reservoir. The black circles represent the 19 points where the two velocity profiles coincided.

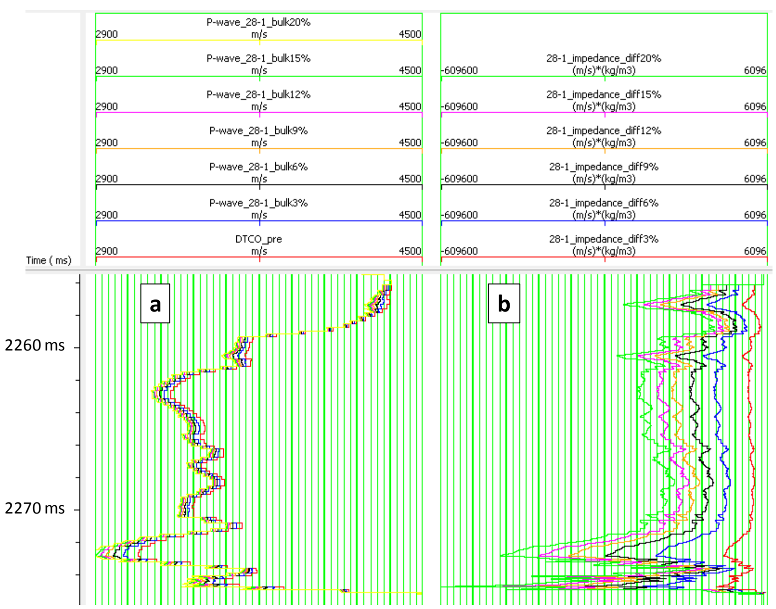

Figure 3. a) P-wave velocities calculated from Gassmann-Wood fluid substitution for 3, 6, 9, 12, 15, and 20% CO_2 saturation. b) Calculated impedance differences for the 28-1 well t for the associated CO_2 saturation.

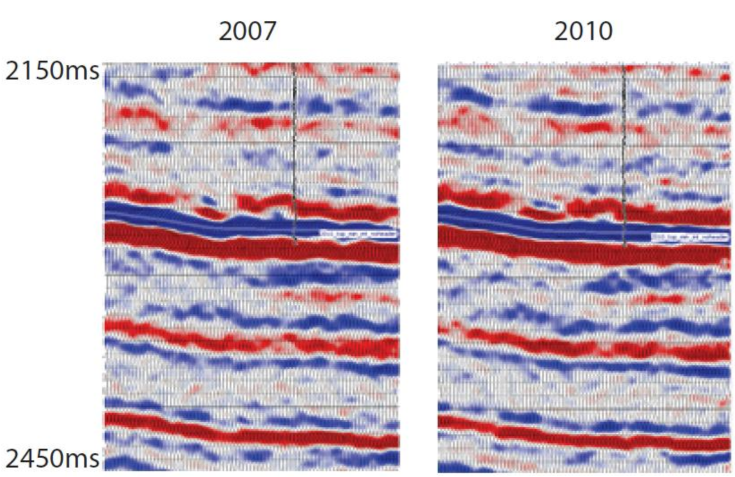

Figure 4. Cross-equalized seismic volumes for 2007 (left) and 2010 (right). The blue line represents the interpreted horizon at the top of the reservoir. The 2010 horizon was used, because the 2007 volume was shifted to the 2010 volume.

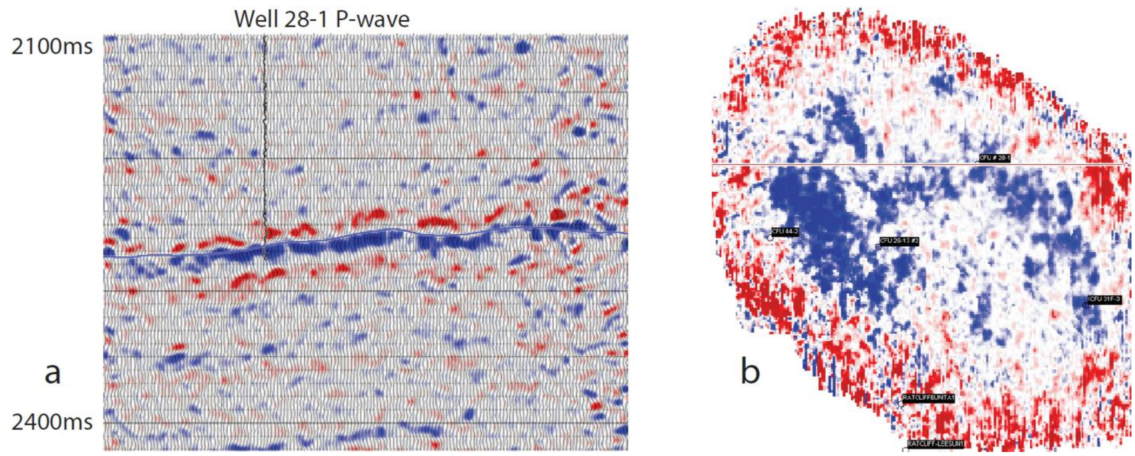

Figure 5. a) 2010-2007 difference volume. The blue line is an interpreted horizon along the reservoir. b) Time slice of initial difference of cross-equalized seismic volumes for 10ms below the reservoir. Areas of blue represent large negative changes in the reservoir.

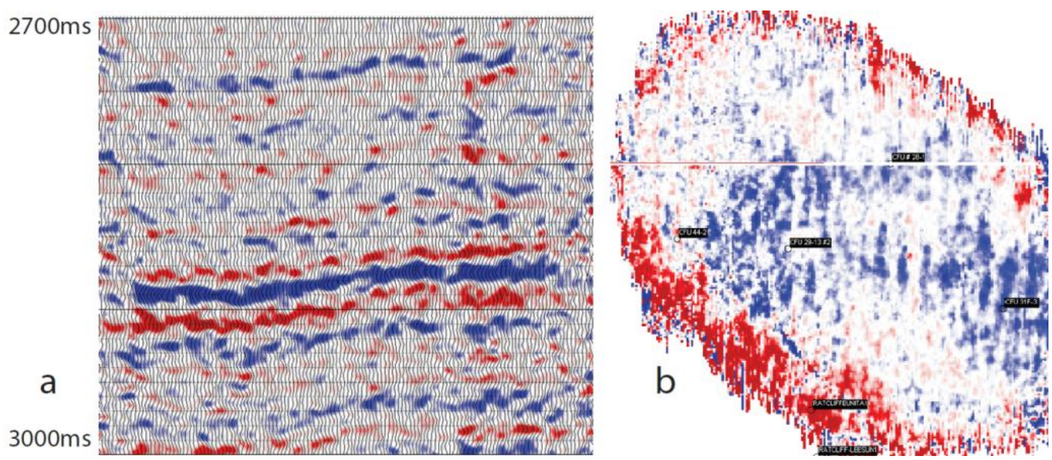

Figure 6. a) Cross-section of cross-equalized difference volume encompassing marker horizon located at about 2800ms. b) Time delay map calculated by cross-correlation within a narrow time window centered at the marker horizon around 2800 ms. The time delay computed throughout the difference volume ranges from 1.2 to 3 ms.

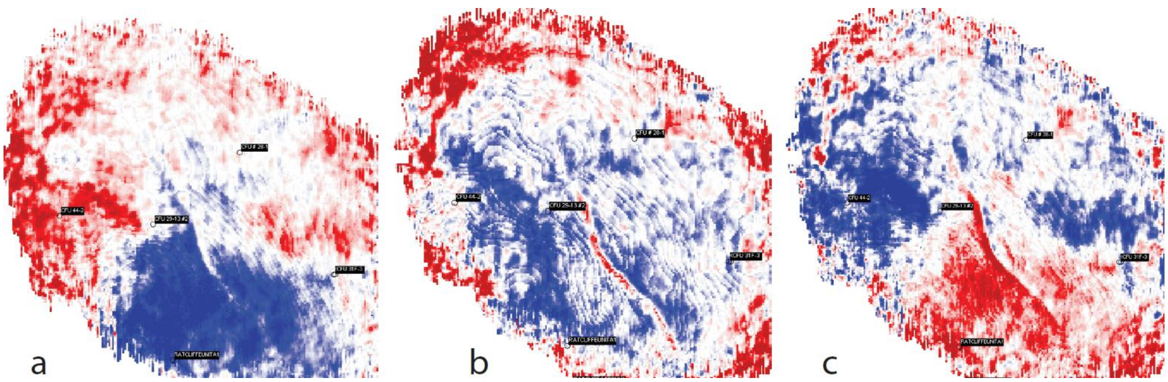

Figure 7. a) Acoustic impedance map for the reservoir horizon computed for: A) 2007 pre-injection volume, b) 2010 post-injection volume and c) the AI difference (2010-2007) over 10ms window below the reservoir horizon. Areas of blue represent large areas of negative AI change in the reservoir.